COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PREFILED STAFF TESTIMONY

APPALACHIAN POWER COMPANY

To revise its fuel factor

Public Version

Case No. PUR-2019-00157

January 16, 2020

Summary of Testimony of Georgianne Ferrell

My testimony contains the following findings and recommendations:

1. In its application in this proceeding, Appalachian Power Company requests to decrease its fuel factor from 2.547 cents per kilowatt-hour ("¢/kWh") to 2.300¢/kWh, effective November 1, 2019.
2. The proposed fuel factor was placed into effect on an interim basis effective November 1, 2019 and decreased the monthly bill of a customer using 1,000 kilowatt-hours by $2.81, from $107.90 to $105.09, a 2.6% decrease.
3. In its application, APCo forecasted an under-recovery position of approximately $36.4 million as of October 31, 2019. Its actual under-recovery position as of that date has now been determined to be $40,642,020, a difference of approximately $4.3 million.
4. While the Company began the current fuel year in an under-recovery position, APCo began its previous fuel year with a greater under-recovery position, and thus the prior-period component of the fuel factor is a reduction from 0.425¢/kWh to 0.261¢/kWh. The Company's in-period component of 2.039¢/kWh is a decrease from the previous in-period factor of 2.122¢/kWh.
5. The Company's application includes historical and forecasted data for its cost of generation, purchases, and off-system sales. As part of this data, the Company provided historical and projected data for individual unit performance.
6. The data provided by the Company as part of its forecast for future unit operation is reasonable and is comparable with historical performance.
7. The Companies 2019 load, fuel, and energy market price forecasts do not appear to be unreasonable. Each is generally consistent with recent trends.
8. Staff believes that the fuel factor proposed by the Company appears reasonable.

PRE-FILED TESTIMONY

OF

GEORGIANNE FERRELL

APPALACHIAN POWER COMPANY
CASE NO. PUR-2019-00157

Q1. PLEASE STATE YOUR NAME AND POSITION AT THE STATE CORPORATION COMMISSION ("COMMISSION").

A1. My name is Georgianne Ferrell. I am a utilities analyst in the Commission's Division of Public Utility Regulation.

Q2. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A2. On September 13, 2019, Appalachian Power Company ("APCo" or "Company") filed an application with the Commission to continue its current fuel factor of 2.547 cents per kilowatt-hour ("¢/kWh") that went into effect on November 1, 2018. On September 27, 2019, the Company filed an amended application ("Application") supporting a request to lower the fuel factor to 2.300¢/kWh, effective for service rendered November 1, 2019 through October 31, 2020 ("Fuel Year").[1]

In its Order Establishing 2019-2020 Fuel Factor Proceeding, issued on October 7, 2019, the Commission docketed the instant case, established a procedural schedule, and directed the Company to provide public notice of the Application. The Commission also directed Commission Staff ("Staff") to investigate the Company's Application and file testimony containing its findings and recommendations on the Application. The

[1] APCo filed the testimony of Eleanor K. Keeton on September 17, 2019, requesting the lower fuel factor of 2.300¢/kWh.

Commission also directed the Company to place its proposed fuel factor of 2.300¢/kWh into effect on an interim basis for service rendered on an after November 1, 2019.

My testimony reviews the reasonableness of the assumptions underlying the Company's projected fuel expenses, generating unit performance, and proposed fuel factor. My testimony also evaluates the Company's forecasted load, fuel prices, and projected PJM[2] energy market prices (collectively, the "2019 Fuel Factor Forecasts") which are the primary inputs used by the Company in its development of the in-period component of the fuel factor.

FUEL FACTOR

Q3. PLEASE SUMMARIZE THE COMPONENTS OF APCO'S PROPOSED FUEL FACTOR.

A3. The Company's proposed fuel factor of 2.300¢/kWh has two components, an in-period component of 2.039¢/kWh and a prior-period factor component of 0.261¢/kWh.

The proposed in-period factor is designed to recover the Company's Virginia jurisdictional fuel expenses[3] projected to be incurred during the Fuel Year. It is based on forecasted Virginia jurisdictional fuel expenses of approximately $283.4 million and forecasted Virginia jurisdictional sales of 13,902,400 megawatt-hours ("MWh").[4] The Company's proposed in-period factor is a decrease from the prior in-period factor of 2.122¢/kWh to 2.039¢/kWh.

The prior-period factor is designed to recover the deferred fuel balance, which the

[2] PJM Interconnection, L.L.C

[3] This also includes purchased power expenses, a credit for 75% of off-system sales margins, PJM Load Serving Entity transmission losses, PJM congestion charges, 100% of incremental transmission line loss margins, Financial Transmission Right revenues, and Green Power revenue credits. The Commission's Definitional Framework of Fuel Expenses for Appalachian Power Company is included as Attachment GF-1.

[4] *See* Direct Testimony of Eleanor K. Keeton ("Keeton Direct") at 5-6.

Company projected to be approximately $36.4 million at the end of October 2019.[5] The proposed prior-period factor is a decrease from the previous prior-period factor of 0.425¢/kWh to 0.261¢/kWh.

In total, the proposed fuel factor would decrease the monthly bill for a residential customer using 1,000 kilowatt-hours by $2.81, from $107.90 to $105.09, a 2.6% decrease.[6]

Q4. HAS THE COMPANY PROVIDED UPDATED INFORMATION RELATIVE TO THE ACTUAL DEFERRED FUEL BALANCE AS OF OCTOBER 31, 2019?

A4. Yes. In response to a discovery request, the Company provided its actual Virginia jurisdictional deferred fuel under-recovery balance as of October 31, 2019. This actual under-recovery balance is $40,642,020,[7] which is approximately $4.3 million below the Company's earlier projected under-recovery balance of approximately $36.4 million.

<u>ENERGY SUPPLY MIX</u>

Q5. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S PROJECTED NET ENERGY SUPPLY AND AVERAGE FUEL COST.[8]

A5. The Company's projected system net energy supply mix and average fuel costs in comparison to the 12 months ending June 30, 2019 are outlined in my Attachment GF-2.

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[5] Keeton Direct at 6.
[6] Keeton Direct at 8.
[7] *See* the Company's supplemental response to Question No. 7 of the Interrogatories and Request for Production of the Staff of the State Corporation Commission (First Set), which I have attached to my testimony in Attachment GF-5.
[8] *See* APCo's September 13, 2019 filing at Appendix P2 Confidential Attachment 1 and P4 Confidential Attachment 1 for projected generation and purchase power levels by individual source.

During the Fuel Year, the Company projects that 82% percent of its total energy supply requirements will be provided by either coal or gas-fired generation.

The Company further forecasts that coal-fired generation will provide 67 percent of the total energy supply at an average fuel cost of 1.961¢/kWh. By comparison, during the 12-month period ending June 30, 2019, coal-fired generation provided 55 percent of total supply at a cost of 2.034¢/kWh.

During the Fuel Year, gas-fired generation is forecasted to supply 15 percent of the total energy supply at an average fuel cost of 1.814/¢/kWh. For the 12-month period ending June 30, 2019, gas-fired generation provided 14 percent of total supply at a cost of 2.204/¢/kWh.

In addition, approximately 7 percent of APCo's projected total energy supply is projected to be provided by the market and 4 percent through wind purchase contracts during the Fuel Year. This is a decrease compared to the twelve months ended June 30, 2019, when market purchases accounted for 19 percent of the energy supply mix.

The remainder of APCo's projected energy supply mix is comprised of purchases from the Ohio Valley Electric Corporation ("OVEC")[9] and a small contribution from its hydro and pumped storage facilities net of pumping energy requirements.

After application of the Off-System Sales margin credit, the total average fuel cost of APCo's net energy supply for the Fuel Year is projected to be 1.868/¢/kWh, a decrease

[9] OVEC was originally organized in 1952, sponsored by 13 electric investor-owned utilities and cooperatives, to serve the U.S. Department of Energy's gaseous diffusion uranium enrichment plant near Portsmouth Ohio, until it shut down in 2000. OVEC has two coal-fired generating stations with a total capacity of approximately 2,400 MW. The sponsoring utilities, based on ownership interest, are entitled to reserve a percentage of capacity and energy. American Electric Power has the largest ownership percentage.

of 0.419/¢/kWh, or 18.3 percent, relative to the average fuel cost over the 12 months ended June 30, 2019. This reflects an expected reduction in the average fuel cost for coal-fired generation, gas-fired generation, and market purchases compared to the period ended June 30, 2019.

Q6. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S CURRENT GENERATION FLEET.

A6. The Company's fossil-fuel generation capacity is currently 72 percent coal-fired and 28 percent gas-fired. The Company also has limited amounts of hydro and pumped storage as well as contracts for wind purchases.

Q7. PLEASE COMMENT ON THE COMPANY'S PROJECTED GENERATING UNIT PERFORMANCE ASSUMPTIONS FOR THE FORECAST PERIOD.

A7. The Company's generation capacity is mostly coal-fired, supplemented by natural gas from the Dresden combined cycle plant, the Ceredo combustion turbine station, the converted Clinch River units, a small amount of conventional hydro, and a pumped hydro facility. My confidential Attachment GF-3 shows forecast period fuel expense and performance data by generation unit including aggregate weighted-average Equivalent Availability Factor ("EAF") and Winter Net Capacity Factor ("CF") for each generation fuel-type.

During the Fuel Year, APCo projects that its coal-fired units will achieve an aggregate weighted-average EAF of 79 percent, an aggregate weighted-average CF of 67 percent, and an aggregate average coal-fired generation thermal efficiency ("Heat Rate") of 9,934 British thermal units ("BTU") per kilowatt-hours.[10] APCo's projected weighted-average EAF for its current coal-fired units are within the range of the actual EAFs achieved on an annual basis since 2016, which ranged between 67 and 80 percent. The Company's projected aggregate coal-fired CF is higher than the last three calendar years, which ranged from 50 to 59 percent.[11] Lastly, the projected aggregate average coal-fired Heat Rate is approximately one percent below the actual Heat Rate of 10,077 achieved over the 12 months ended July 31, 2019.[12]

APCo projects that the Company's most efficient unit, the Dresden combined-cycle generating unit, will continue to operate as a baseload plant. During the 13 months ended July 31, 2019, it consumed over 31.8 million MMBtus. [13] During the Fuel Year, APCo projects that its Dresden unit will achieve an EAF of **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]**, a CF of **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]**, and a Heat rate of **[BEGIN CONFIDENTIAL** [redacted] **END CONFIDENTIAL]** per kilowatt-hours.[14] The small amounts of projected generation from the other gas-fired units and the conventional and pumped hydro facilities are comparable to actual historical experience.

The Staff has reviewed the projected EAFs, CFs, Unplanned Outage Rates, Planned Outages, Heat Rates, and average fuel costs of the Company's generating resources. Staff

[10] *See* the Company's response to Question No. 3 of the Interrogatories and Request for Production of the Staff of the State Corporation Commission (First Set), which was received on October 15, 2019.
[11] *See* the Company's response to Question No. 4 of the Interrogatories and Request for Production of the Staff of the State Corporation Commission (First Set), which was received on October 15, 2019.
[12] *See* Company's response to Question No. 3 of the Interrogatories and Request for Production of the Staff of the State Corporation Commission (First Set), which was received on October 15, 2019.
[13] *See* APCo's September 13, 2019 filing at Attachment 1 of Appendix A3.
[14] *See* Company's response to Question No. 3 of the Interrogatories and Request for Production of the Staff of the State Corporation Commission (First Set), which was received on October 15, 2019.

concludes that the Company's fuel expense projections reflect reasonable generating unit performance and are generally consistent with historical performance.

2019 FUEL FACTOR FORECASTS

Q8. HOW ARE THE COMPANY'S 2019 FUEL FACTOR FORECASTS USED IN THE DEVELOPMENT OF THE FUEL FACTOR?

A8. The Company's 2019 Fuel Factor Forecasts are used by APCo to determine the in-period component of its fuel factor. First, the Company determines the internal load requirements for APCo and its Virginia jurisdiction. This represents the Company's expected net energy requirement for the Forecast Period. The Company's fuel forecasts and projected PJM energy market prices are then used to determine the anticipated includable cost to APCo associated with meeting the expected net energy requirement. Together, APCo's net energy requirement and includable cost are used to derive the net energy cost forecast, which represents the cost per unit of energy that APCo expects to incur over the Forecast Period.

The net energy cost forecast is derived using the PLEXOS simulation model ("PLEXOS"), a production costing computer program. PLEXOS attempts to model APCo's operations of its generating units, along with other PJM members, to meet APCo's total PJM load requirements on the most economic basis, based on price offers, subject to transmission limitations.

Q9. ARE THE COMPANY'S 2019 FUEL FACTOR FORECASTS THE SAME FORECASTS USED IN THE COMPANY'S MOST RECENT INTEGRATED RESOURCE PLAN ("IRP") PROCEEDING?

A9. No. The 2019 Fuel Factor Forecasts rely on updated forecasts. APCo's 2019 IRP, filed on May 1, 2019, was based on APCo's 2018 load forecast (published in June 2018) and the coal, gas, and PJM energy prices were based on the 2019 H1 Fundamentals Forecast (published in April 2019). In contrast, the 2019 Fuel Factor Forecasts were based on the 2019 Load Forecast (published in May 2019) and the coal, gas, and PJM energy prices were all based on the data from the Company's Commercial Operations group dated June 20, 2019, June 28, 2019, and April 15, 2019, respectively. [15]

Q10. HOW DID THE STAFF EVALUATE THE COMPANY'S 2019 FUEL FACTOR FORECASTS?

A10. Staff does not believe that any forecasting methodology is perfect, and each has its own set of potential issues. Regardless of the model or approach, special attention must be given to the input assumptions and whether those assumptions reasonably reflect future variable conditions. In assessing the 2019 Fuel Factor Forecasts, Staff compared APCo's actual monthly peak demand, internal energy requirements, coal and natural gas costs, and PJM energy market prices to the Company's prior fuel factor forecasts. This comparison illustrates the Company's track record in producing forecasts that reasonably reflect actual conditions.

ASSESSMENT OF LOAD FORECASTS

Q11. DID THE COMPANY PROVIDE FORECASTS OF ITS EXPECTED LOAD OBLIGATIONS IN THE 2019-2020 FORECAST PERIOD?

[15] *See* the Company's response to Staff Interrogatory No. 1-11 included in Attachment No. GF-5.

A11. Yes. APCo provided forecasts of its monthly peak demand and corresponding internal energy requirements ("Load Forecasts") for the 2019-2020 Forecast Period. The Company's monthly peak demand forecast represents APCo's monthly internal peak demand in megawatts ("MW") for APCo while the Company's internal energy requirements forecast represents the Company's monthly giga-watt hour ("GWH") energy sales anticipated to its Virginia jurisdictional customers over the 2019-2020 Forecast Period. The Load Forecasts are shown in comparison to the Company's actual load in Figure 1 and Figure 2 below.

Figure 1. APCo Forecasted and Actual Monthly Peak Demand

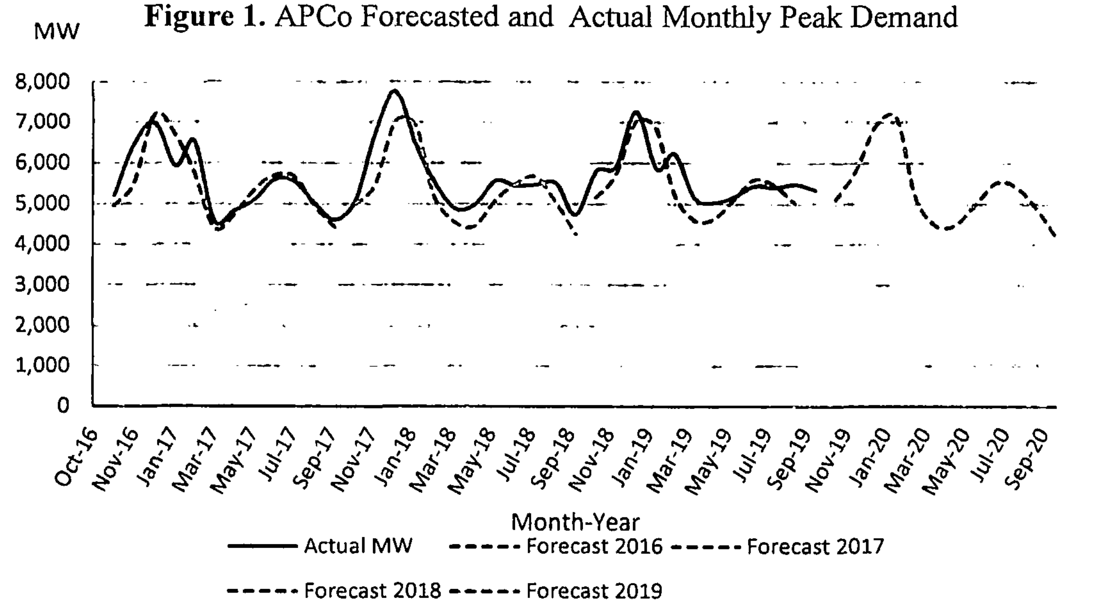
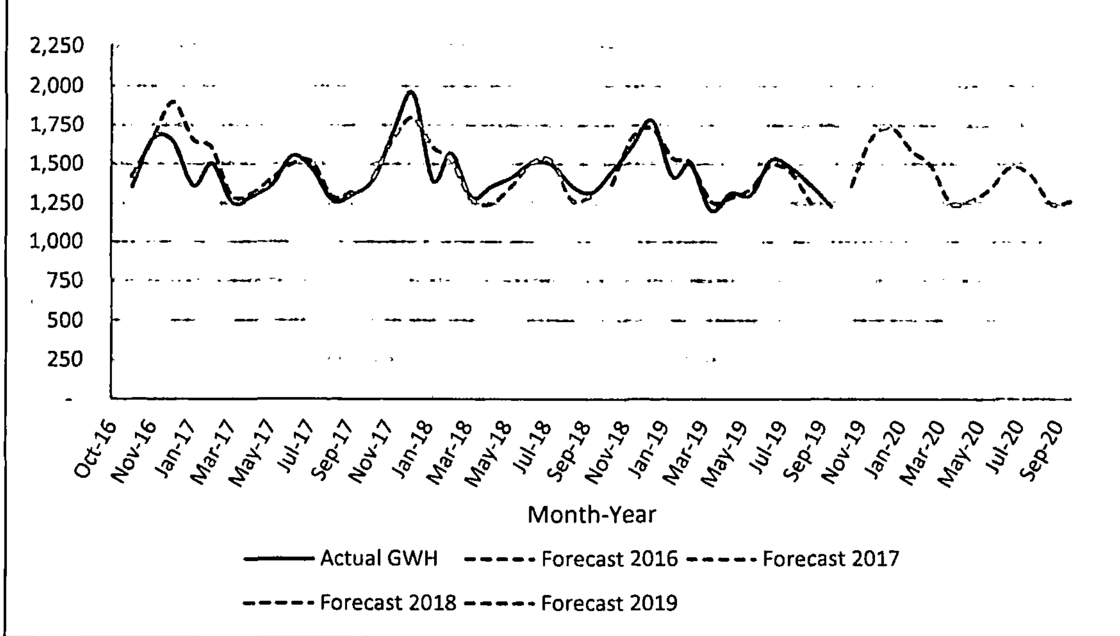


Figure 2. APCO Forecasted and Actual Monthly Internal Energy



Q12. CAN YOU PLEASE BRIEFLY DESCRIBE THE COMPANY'S LOAD FORECASTS?

A12. The Company's 2019 Load Forecasts depict general seasonal variation in the Company's load patterns. Specifically, as shown on Figure 1 and Figure 2, APCo's peak demand and internal energy requirements are projected to rise to a total system peak in the winter and a smaller peak in the summer months while remaining lower in the shoulder months of fall and spring. This is consistent with typical load patterns among utilities that tend to peak in the winter and summer months and is also consistent with APCo's historical pattern of being a winter peaking utility, *i.e.* experiencing its highest annual system peak demand in the winter period. The 2019 Load Forecasts are also generally consistent with the Company's Load Forecasts submitted in its prior two fuel factor proceedings.

Q13. WHAT IS YOUR EVALUATION OF THE REASONABLENESS OF THE COMPANY'S LOAD FORECASTS?

A13. The Company's 2019 Load Forecasts do not appear to be unreasonable. Figure 1 and Figure 2 above show the Company's 2016, 2017, and 2018 Load Forecasts in comparison to the Company's actual experienced peak demand and internal energy sales. Overall, these forecasts tracked well with the Company's actual load patterns. As previously stated, the Company's 2019 Load Forecasts are generally consistent with the Company's prior Load Forecasts.

ASSESSMENT OF FUEL FORECASTS

Q14. DID THE COMPANY PROVIDE FORECASTS OF ITS EXPECTED FUEL COSTS IN THE 2019 – 2020 FORECAST PERIOD?

A14. Yes. APCo provided forecasts of its expected monthly delivered coal and natural gas prices ("Fuel Forecasts") for the 2019-2020 Forecast Period for each of its coal and natural gas fired generating units.[16] The Company's current and previous Fuel Forecasts are shown in comparison to the Company's actual incurred costs of coal and natural gas in Figures 3 and 4 below.

[16] *See* Company's response to Question No. 9 of the Interrogatories and Request for Production of the Staff of the State Corporation Commission (First Set).

Figure 3. APCo Forecasted and Actual Monthly Coal Prices

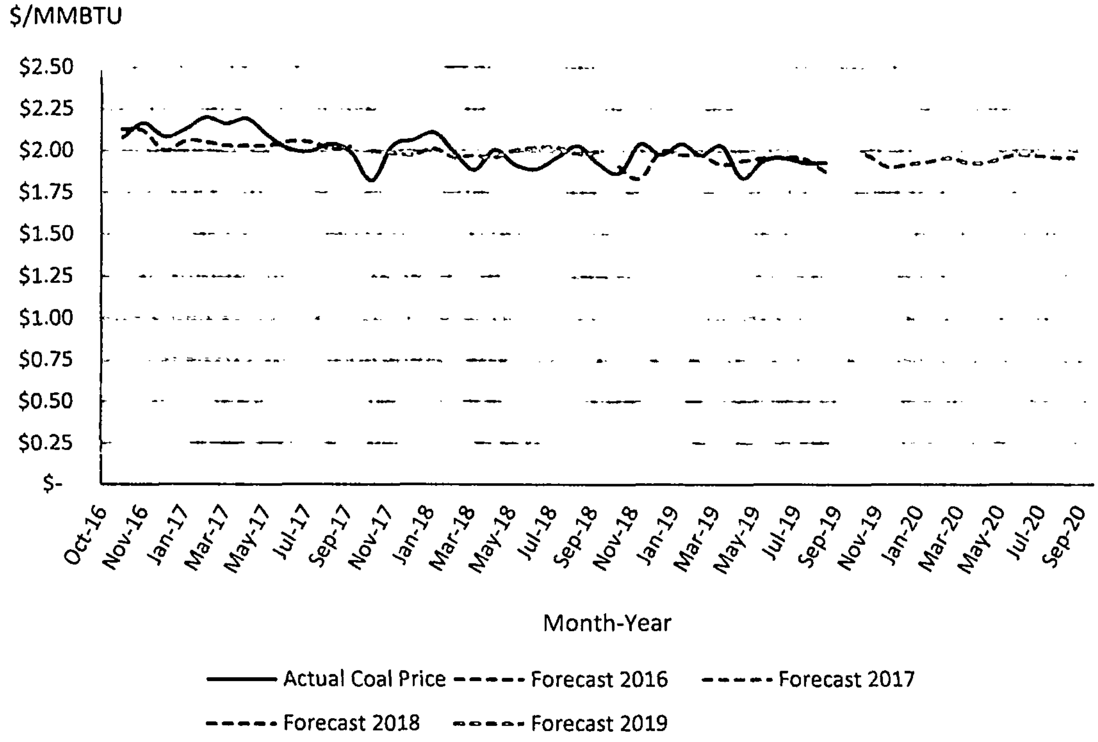
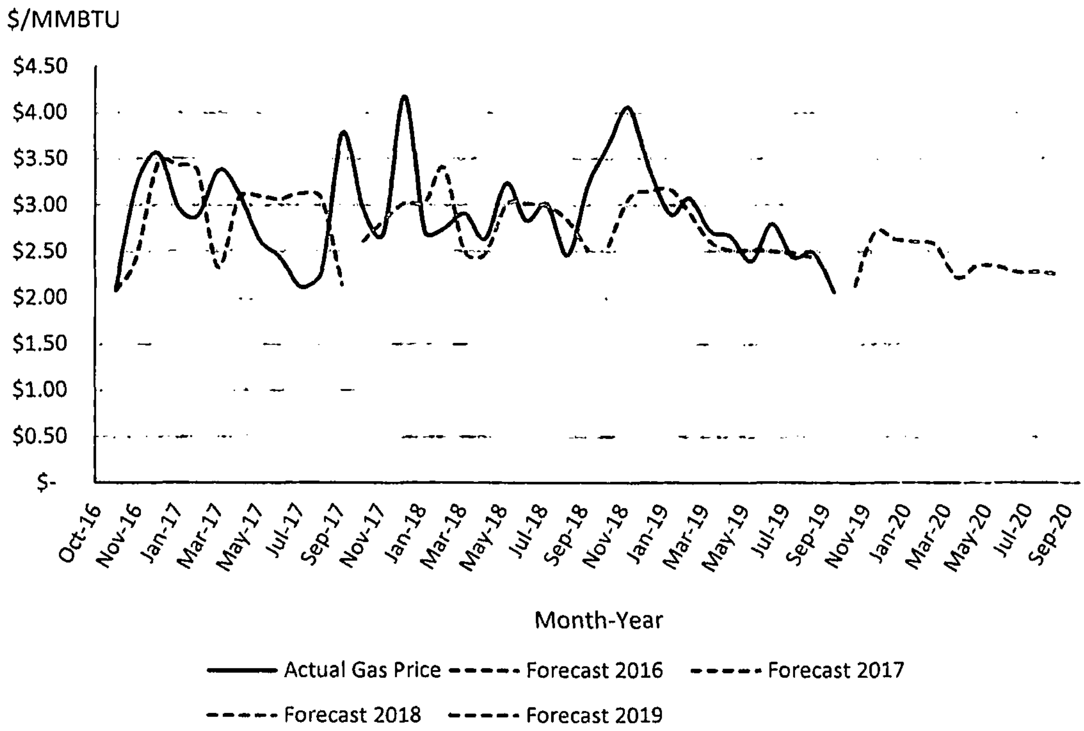


Figure 4. APCO Forecasted and Actual Monthly Natural Gas Prices



Q15. CAN YOU PLEASE BRIEFLY DESCRIBE THE COMPANY'S FUEL FORECASTS?

A15. Yes. The Company's 2019 coal price forecast in Figure 3 depicts a relatively stable trend in the commodity cost of delivered coal. This is consistent with the Company's prior forecasts and the Company's actual incurred coal costs.

APCo's natural gas price forecast depicted in Figure 4 shows general seasonal variation in the market price of natural gas. The Company's 2019 natural gas price forecast projects the Company's average price of natural gas to peak in the winter and fall through September 2020.

Q16. WHAT IS YOUR EVALUATION OF THE REASONABLENESS OF THE COMPANY'S COAL PRICE FORECAST?

A16. The Company's short-term coal price forecast does not appear to be unreasonable. When compared to the actual observed results, the Company's historic coal price forecasts generally track with the actual incurred costs.[17] Staff also notes that a portion of APCo's coal costs within the 2018 Forecast Period are negotiated under long-term contracts. Long-term contracts, all else being equal, result in less exposure to market volatility and reduce price uncertainty.

[17] Combined, APCo's 2016, 2017, and 2018 coal price forecasts exhibited an average forecasting error (mean absolute percentage error, or "MAPE") of 3.5% and a mean percentage error ("MPE") of -0.6%, with 18 (51.4%) forecasted monthly values slightly lowly than actual observed monthly prices and 17 (49.6%) values slightly greater than actual observed monthly prices.

Q17. WHAT IS YOUR EVALUATION OF THE REASONABLENESS OF THE COMPANY'S NATURAL GAS PRICE FORECAST?

A17. Overall, APCo's short-term natural gas price forecasts do not appear to be unreasonable[18] although there is error in the historic forecasts submitted in the Company's prior fuel factor proceedings. The Company's 2019 natural gas price forecast is generally consistent with typical seasonal patterns in the market price for natural gas.

Q18. PLEASE ELABORATE ON THE ERROR IN THE PRIOR NATURAL GAS FORECASTS.

A18. The Company's historic natural gas price forecasts reflect several sizeable deviations from actual observed natural gas prices.[19] The actual observed natural gas prices depicted in Figure 4 show considerable volatility in recent years likely resulting from variation in weather patterns combined with pipeline capacity constraints associated with the transportation of natural gas. The significant spikes that occurred in the fall of 2017, January 2018 and the fall of 2018 resulted in the Company's forecasted values being slightly underestimated on average.[20] Such volatility can be difficult to forecast accurately as forecasts tend to rely on historical average weather patterns and the assumption of normal weather. However, there has not been an extensive pattern of overestimation or

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[18] While Staff does not find APCo's short term natural gas price forecasts to be unreasonable, in APCo's most recent IRP proceeding (Case No. PUR-2019-00058) Staff expressed concerns with APCo's long term natural gas and power price forecasts.

[19] Combined, APCo's 2016, 2017, and 2018 natural gas price forecasts exhibited a MAPE of 14.7% and a MPE of -1.5%., with 21 (60%) forecasted values lower than actual observed monthly prices and 14 (40%) greater than actual observed monthly prices.

[20] Combined, APCo's 2016, 2017, and 2018 natural gas price forecasts exhibited a MAPE of 14.7% and a MPE of -1.5%.

underestimation, and so for these reasons the deviations do not appear to indicate a significant flaw in the underlying forecasting methodology.

ASSESSMENT OF ENERGY MARKET PRICE FORECASTS

Q19. DID THE COMPANY PROVIDE FORECASTS OF EXPECTED PJM ENERGY MARKET PRICES?

A19. Yes. The Company provided forecasts of its expected hourly PJM energy market prices applicable to APCo's expected energy market sales and purchases.[21] Additionally, APCo also provided the PJM energy market price forecasts used in the Company's 2016 and 2017 fuel factor proceedings. The energy market price forecasts are shown in comparison to the actual hourly locational marginal prices for APCo in Figure 5 below.

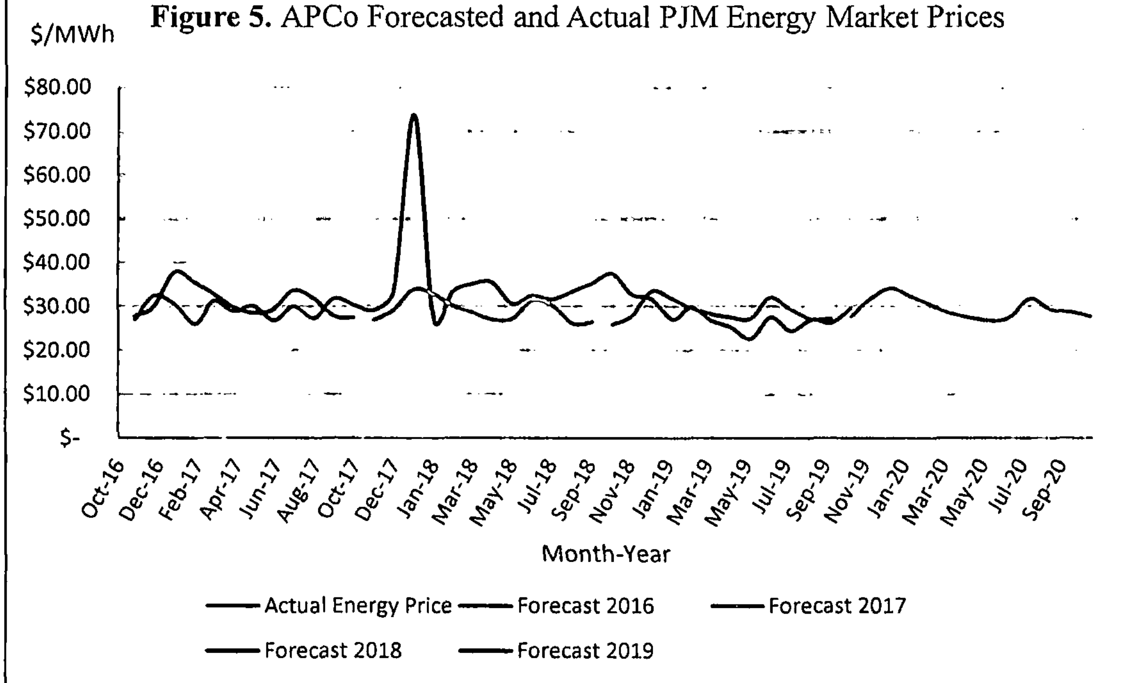

Figure 5. APCo Forecasted and Actual PJM Energy Market Prices

[21] *See* response to Question No. 10 of the Interrogatories and Request for Production of the Staff of the State Corporation Commission (First Set).

Q20. CAN YOU PLEASE BRIEFLY DESCRIBE THE COMPANY'S 2019 ENERGY MARKET PRICE FORECAST?

A20. Like the previous forecasts, the Company's 2019 PJM energy market price forecast depicts general seasonal variation in market price patterns. Specifically, Figure 5 projects energy market prices to rise to two peaks in the winter and summer months while remaining lower in the shoulder months of fall and spring. This is consistent with typical market patterns within PJM where market prices tend to peak in the winter and summer months due to greater heating and cooling demand. The 2019 PJM energy market price forecast is also generally consistent with the Company's prior energy market price forecasts submitted in prior fuel factor proceedings.

Q21. WHAT IS YOUR EVALUATION OF THE REASONABLENESS OF THE COMPANY'S ENERGY MARKET PRICE FORECAST?

A21. The Company's 2019 energy market price forecast does not appear to be unreasonable. Although APCo's historic forecasts have had error,[22] there does not appear to be a tendency toward underestimation or overestimation in the forecasts.[23]

STAFF CONCLUSIONS

Q22. HAS THE COMPANY MET THE STANDARDS SET BY THE COMMISSION FOR EVALUATING FUEL COST PROJECTIONS OF ELECTRIC UTILITIES?

[22] The previously-mentioned colder than average weather was the primary factor contributing to the spike in PJM energy market prices in January 2018.

[23] In the 2016, 2017, and 2018 forecast years combined, 50% of the forecasted values were underestimated and 50% were overestimated.

A22. In its 1989 Session, the Virginia General Assembly adopted Senate Resolution No. 156, which requested the State Corporation Commission to establish standards for evaluating fuel cost projections of electric utilities. On November 27, 1990, the Commission issued its Final Order in Case No. PUE-1990-00004, adopting such standards. These standards are provided as Attachment No. GF-4 to my testimony. In the present fuel factor proceeding, the Company has generally complied with those requirements.

Q23. WHAT ARE THE STAFF'S CONCLUSIONS AND RECOMMENDATIONS REGARDING THE COMPANY'S ESTIMATED FUEL EXPENSES AND PROPOSED FUEL FACTOR?

A23. The Staff believes that in total the Company's projected fuel expenses for the forecast period and the resulting proposed fuel factor are generally reasonable. The Staff recommends that the Commission approve the Company's proposed fuel factor of 2.300¢/kWh, which is already effective on an interim basis.

Q24. DOES THIS CONCLUDE YOUR TESTIMONY?

A24. Yes.

ATTACHMENT GF-1

VIRGINIA STATE CORPORATION COMMISSION'S DEFINITIONAL FRAMEWORK OF FUEL EXPENSES FOR APPALACHIAN POWER COMPANY

a. The cost of fossil fuels shall be those items initially charged to account 151 and cleared to accounts 501, 518 and 547 on the basis of fuel used. In those instances where a fuel stock account (151) is not maintained, e.g., gas for combustion turbines, the amount shall be based on the cost of fuel consumed and entered in account 547.

b. The cost of nuclear fuel shall be the amount contained in account 518, excluding lease finance charges, except that if account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account.

c. Total energy costs associated with purchased power and charged to account 555 shall be recoverable as fuel costs. The demand component of such power purchases shall be recoverable as fuel costs except when such purchases are made for reliability reasons or the maintenance of reserve margin requirements.

d. Energy revenues associated with off-system sales of power shall be credited against fuel factor expenses in an amount equal to the total incremental fuel factor costs incurred in the production and delivery of such sales. In addition, 75 percent of the total margins from off-system sales, or such smaller percentage of such margins as may be approved by the Virginia State Corporation Commission, shall be credited against fuel factor expenses. In the event such margins result in a net loss to the Company, no charges shall be applied to fuel factor expenses. For purposes of this provision, "margins from off-system sales" shall mean the total revenues received from off-system sales transactions less the total incremental costs incurred.

e. All refunds of fuel costs resulting from overcharges, late delivery, or any other reason and all recoveries and adjustments of whatever nature affecting the price of fuel shall be passed on through these proceedings.

f. Company shall be permitted to adjust for system losses through development of a fuel factor based upon fuel costs divided by sales or through the application of a separately derived loss factor applied to a fuel factor based on net energy requirements.

g. Company shall be permitted to adjust its fuel factor to recover gross receipts taxes.

ATTACHMENT GF-2

APPALACHIAN POWER COMPANY
CASE NO. PUR-2019-00157
ENERGY SUPPLY MIX - 12 MONTHS PROJECTED VS ACTUAL 12 MONTHS ENDED JUNE 30, 2019

	12-MONTH PROJECTION November 1, 2019 - October 31, 2020				ACTUAL 12-Months Ended June 30, 2019			
	Expense ($000)	Supply (GWh)	Mix (Percent)	Cents/ per kWh	Expense ($000)	Supply (GWh)	Mix (Percent)	Cents/ per kWh
Net Generation:								
Coal-fired Generation	490,461	25,012	67%	1.961	398,132	19,575	55%	2.034
Gas-fired Generation	96,274	5,306	15%	1.814	106,196	4,819	14%	2.204
Hydro and Pumped Storage (Net of Pumping Energy)		386	1%			852	1%	
Total Net Generation	586,735	30,704	82%	1.911	504,328	25,246	71%	1.998
Purchases:								
Market Purchases	69,811	2,786	7%	2.506	213,831	6,824	19%	3.133
OVEC	38,746	1,543	4%	2.512	39,540	1,837	5%	2.152
Wind Purchases (1)	51,556	1,340	4%	3.847	56,968	1,316	4%	4.329
Summersville Hydro		220	1%			261	1%	
PJM Marginal Losses		785	2%					
Out of Period Adjustment					(342)	(6)		
Total Purchases	160,113	6,674	18%	2.399	309,997	10,233	29%	3.030
Total Energy Supply	746,848	37,378	100%	1.998	814,325	35,479	100%	2.295
Fuel for Off-system Sales	(97,733)	(4,641)		2.106	(73,445)	(3,145)		2.335
100% Incremental Trans. Line Loss Margins	(11,348)				(3,339)			
PJM LSE Transmission Losses	20,200				16,422			
FTR Revenues Net of Congestion Charges	(15,418)				(5,081)			
Green Power Revenue Credit	(8)							
Net Energy Supply	642,541	32,737	88%	1.963	748,880	32,334	91%	2.316
Less 75% OSS Margins	(31,020)				(9,378)			
Net Energy Supply Less OSS Margins	611,521	32,737	88%	1.868	739,503	32,334	91%	2.287

(1) Fuel expenses reflect non-incremental costs of wind power purchases from Camp Grove, Fowler Ridge, Grand Ridge, Beech Ridge and Bluff Point.

ATTACHMENT GF-3

APPALACHIAN POWER COMPANY
CASE NO. PUR-2019-00157
PROJECTED GENERATING UNIT PERFORMANCE
NOVEMBER 1, 2019 THROUGH OCTOBER 31, 2020

	Winter MDC (MW)	Fuel Expense ($000)	Net Generation (GWh)	Average Fuel Cost (¢/kWh)	Average Fuel Cost (¢/MBtu)	EAF (%)	CF (%)	Average Heat Rate (Btu/kWh)
Amos 1	800	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Amos 2	800	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Amos 3	1,330	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mountaineer 1	1,320	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Coal	4,250	490,461	25,012	1.961	197.39	79%	67%	9,934
Ceredo	516	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Clinch River 1	230	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Clinch River 2	235	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dresden Comb Cycle	659	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Gas	1,640	96,274	5,306	1.814	246.05	80%	37%	7,374
Net Hydro & Pumping Energy			386					
Total	5,890	586,735	30,704	1.911	204.01	79%	60%	9,367
Coal Percent	72%	84%	81%					
Natural Gas/Steam Percent	28%	16%	17%					

ATTACHMENT GF-4

Standards for Fuel Cost Projections of Electric Utilities

- A sophisticated "state-of-the-art" production costing model should be utilized for projecting fuel expenses.

- Key input data and assumptions should reflect historical data. Any significant deviation from historic trends should be adequately explained and evaluated for reasonableness.

- Key input data such as load forecasts, generating unit characteristics, fuel data, and system parameters should be developed in the same relative time period and reflect consistent assumptions.

- Demand forecasts should be current and reflect economic growth, normal weather, the price of electricity, elasticity assumptions, appliance saturations, income, and population changes in the utility's service area. They should also reflect projections of energy, peak demand and the effects of demand-side options.

- Expected fuel prices should reflect historic fuel costs adjusted for any known dynamics of the projection period: i.e., labor contracts, expected operation of the spot market, current fuel contracts in the world fuel market, inventory levels and fuel availabilities, purchasing volumes, coal severance taxes, etc.

- Unit operations should consider planned maintenance, forced outages, expected dispatch levels, historical performance levels, and seasonal capabilities, as well as on-going enhancements or unit deterioration.

- Dispatch order should reflect such variables as system economics, unit availabilities, minimum operating levels, heat rates, and terms and conditions of purchased power contracts.

- Purchase power levels should consider need, system economics, power availability, and transmission constraints.

- Projections supporting the development of cogeneration rates should include a comparison of key input data and assumptions from the last fuel projections filed with the Commission. Major changes should be adequately explained.

ATTACHMENT GF-5

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2019-00157
Interrogatories and Requests for the Production
of Documents by the STAFF OF THE STATE CORPORATION COMMISSION
Staff's First Set
To Appalachian Power Company

Interrogatory Staff 1-007:

During the course of this proceeding, provide the most recent month's actual Virginia Deferred Fuel balance, as soon as it is available. Please also provide the resulting updated October 31, 2020 Virginia Deferred Fuel balance projection.

Response Staff 1-007:

Please see Staff 1-007, Attachment 1, for the requested information.

Supplemental Response Staff 1-007:

Please see Staff 1-007 Supplemental Attachment 1 for the November 2019 actuals.

The foregoing response is made by Eleanor K. Keeton, Regulatory Consultant Sr, on behalf of Appalachian Power Company.

APPALACHIAN POWER COMPANY
VIRGINIA JURISDICTION
PROJECTED FUEL COST RECOVERY POSITION - UPDATE
AS OF NOVEMBER 2019

	Virginia Jurisdictional Energy Sales	Fuel Factor Recovery (a)	Total Company Fuel Cost (b)	Energy Allocation Factor (c)	CSP Capacity Sales	Renewal Rider Revenue Credit	Virginia Retail Fuel Cost Col. (3) x Col. (4) Less Col (5)	Monthly NEC Over (Under) Recovery Col. (2)- (6)	Cumulative Fuel Cost Over(Under) Recovery Position
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	(KWH)	($)	($)		($)	($)	($)	($)	($)
Balance at June 2018									(66,801,836)
(A) July	1,204,313,390	26,121,557	58,141,783	0.457494	(481,017)	119	16,118,381	10,003,176	(56,798,660)
(A) August	1,216,272,285	26,380,946	55,204,348	0.457907	(481,017)	579	24,796,861	1,584,085	(55,214,575)
Entry FA0322A - Adjustment entry due to market change in June 2017								(3,644,544)	(58,859,119)
(A) September	1,109,477,782	24,064,573	68,673,723	0.463755	0	1,521	31,846,261	(7,781,688)	(66,640,807)
(A) October	1,096,039,944	23,773,106	68,549,911	0.449689	0	1,581	30,824,560	(7,051,454)	(73,692,261)
(A) November	1,203,122,563	30,643,532	74,436,403	0.472646	0	510	35,181,558	(4,538,026)	(78,230,287)
Jan - Dec 2018 Adj Non-Incremental Wind Costs								(1,351,013)	(79,581,300)
(A) December	1,329,791,135	33,869,780	77,704,800	0.473142	0	588	36,764,816	(2,895,036)	(82,476,336)
REVISED Jan - Dec. 2018 Adj Non-Incremental Wind Costs								(257,156)	(82,733,492)
(A) January 2019	1,450,829,301	36,952,622	73,192,922	0.469177	0	377	34,340,059	2,612,563	(80,120,929)
(A) February	1,181,818,153	30,100,908	59,014,307	0.468309	0	504	27,636,427	2,464,481	(77,656,448)
2018 NEC Allocation Adjustment (d)								493,950	(77,162,498)
NER adjustment 3/29/19									(77,162,498)
(A) March	1,278,465,634	32,562,520	68,989,552	0.463802	0	486	31,997,006	565,514	(76,596,984)
(A) April	978,817,479	24,930,481	51,692,106	0.463179	0	0	23,942,698	987,783	(75,609,201)
(A) May	1,027,417,530	26,168,324	41,255,099	0.445060	0	0	18,360,994	7,807,330	(67,801,871)
Jan-May 2019 Adj. Non-incremental wind costs								3,069,861	(64,732,010)
(A) June	1,089,610,765	27,752,386	42,644,786	0.477257	0	458	20,352,065	7,400,321	(57,331,689)
(A) July	1,260,623,035	32,108,069	54,457,340	0.452157	0	402	24,622,865	7,485,204	(49,846,485)
(A) August	1,197,687,546	30,505,102	56,033,786	0.459677	0	369	25,757,074	4,748,028	(45,098,457)
(A) September	1,085,323,083	27,643,179	56,314,384	0.448401	0	366	25,251,060	2,392,119	(42,706,338)
(A) October	998,465,753	25,430,923	52,476,086	0.445288	0	367	23,366,605	2,064,318	(40,642,020)
(A) November	1,210,563,762	27,842,967	66,064,360	0.460420	0	275	30,417,077	(2,574,110)	(43,216,130)

(a) July 2019 - October 2019: Col. 1 x $0.02547/kWh   November 2019: Col. 1 x $0.02300/kWh
(b) Excludes demurrage expense.
(c) Estimate Virginia energy allocation factor
(d) Adjustment to recognize the difference between the sum of monthly- allocated NEC and annually- allocated NEC
(A) Actual; (E) Booking Estimate; (P) Projected.

COMMONWEALTH OF VIRGINIA
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Staff's First Set
To Appalachian Power Company

<u>Interrogatory Staff 1-011:</u>

Please refer to the Company's responses to Staff Interrogatory Nos. 8(c), 9(c) and 10(c) above. For the forecasted period November 2019 through October 2020, please discuss if and how these forecasts differ from the forecasts submitted in the Company's most recent IRP proceeding, Case No. PUR-2019-00058.

<u>Response Staff 1-011:</u>

The APCo IRP, which was filed May 1, 2019, was based on the 2018 Load Forecast published in June 2108; the coal, gas and PJM energy prices were based on the 2019 H1 Fundamentals Forecast published in April 2019.
The Virginia Fuel Factor which was filed September 13, 2019 was based on the 2019 Load Forecast published in May 2019; the coal, gas and PJM energy prices were all based on data from the Commercial Operations group dated 06/20/2019, 06/28/2019 and 04/15/2019, respectively.

The foregoing response is made by Nancy A. Heimberger, Financial Analyst Sr. Staff, on behalf of Appalachian Power Company.